# CHAPTER I. INTRODUCTION

The decade of the 1970s witnessed a series of profound changes in the circumstances under which electric utilities operate. While in earlier decades the industry had experienced steady growth in demand together with declining costs, the 1970s were a time of disturbance. An upheaval occurred in energy prices, while internally the industry had to face rising fuel and capital costs together with new costs imposed by environmental policies. Future demand for electricity became more difficult to forecast. These problems were exacerbated by a regulatory process that was not designed to deal with them. As a consequence, the efficiency of the electric utility sector may be eroding.

The future of electric utilities may require significant adaptation to these new conditions through changes in generating capacity. At present, the utilities find it difficult to raise the funds needed for investment in least-cost generation. Inability to raise capital occurs in many industries, but electric utilities are unique in four respects. First, they deploy more capital than any other industry--30 percent of total U.S. manufacturing investment annually. Second, because they have local monopoly franchises, inefficiencies in electricity production are ultimately imposed on consumers in the form of higher costs. Third, the utility capital problem is bound up with the present regulatory system, and a solution to it may require a change in public policy on the federal level. Fourth, utilities are major consumers of oil and gas and hence of special interest to national energy policy.

Inadequacies in the present regulatory treatment of utilities may be costly to the economy in several ways. First, utilities may use too much oil and gas because they are unable to make the capital commitments necessary to replace oil- and gas-fired capacity with coal-fired or nuclear capacity--raising the long-term costs of electricity and keeping oil imports unnecessarily high. Second, utilities may have to pay high interest rates for capital because their regulatory treatment renders them unattractive to investors. Third, the supply of electricity may fail to keep pace with the demands of the economy.

This report reviews a number of policy options intended to promote improved economic performance in the electric utility industry. Chapter II begins with a discussion of the regulatory environment of public utilities and the obstacles this environment poses to greater efficiency. In particular, the chapter reviews the financial condition of the electric utility industry and its relationship to the regulatory process. Chapter III deals with the most widely noted manifestation of poor economic performance in the electric utility sector--the continued uneconomic consumption of oil and gas. The economics of converting or retiring such units is discussed. Chapter IV analyzes the possible effects of alternative policies designed to assist utilities in promoting economic efficiency through capacity adjustment.

# CHAPTER II. RATE BASE REGULATION AND THE ECONOMIC PERFORMANCE OF ELECTRIC UTILITIES

Most privately-owned electric utilities are granted monopoly franchises for their service areas, and their prices are regulated at both the federal and state levels. Interstate wholesale electricity transactions, roughly 5 percent of all utility sales, are regulated by the Federal Energy Regulatory Commission (FERC). But the bulk of electricity transactions are intrastate retail sales of electricity, and these are regulated by state public utility commissions (PUCs).

The primary concern of PUCs is to assure that ratepayers are given reliable service at "just and reasonable" rates, while allowing adequate revenues for the utilities providing such service. PUCs do this by setting electricity prices through a process termed "rate base regulation." This chapter describes the rate base regulatory process and its performance, particularly during the 1970s. It also discusses the financial condition of the electric utility industry and its dependence on the regulatory process.

## ELECTRIC UTILITY REGULATION

Electricity sales have been regulated since the beginning of this century. Current regulatory procedures, however, owe much to the Supreme Court's decision in the Hope Natural Gas case of 1944.

### The Hope Decision

In the early 1900s, the major debate in electricity rate cases centered on determination of a "fair value" for a utility's assets, or "rate base." Utilities argued that their assets should be valued at original cost during deflationary periods and at replacement cost during inflationary periods. Over time, original cost became the predominant method of rate base valuation, and the debate shifted to the determination of a "fair" rate of return. One impetus for this shift was the Hope decision 1944. Essentially pragmatic, it stated:

> Rates which enable the company to operate successfully, to maintain its financial integrity, to attract capital, and to compensate its investors for the risks assumed certainly cannot be condemned as invalid, even though they might

produce a meager return on the so-called "fair value" rate base.[1]

Three regulatory principles have been distilled from this decision:

- o Investors in utilities should earn a return comparable to that earned in other businesses with comparable risks and uncertainties;
- o The allowed return should ensure the financial integrity of investments in a utility; and
- o The allowed return should be sufficient to attract the necessary capital for a utility.

The Hope decision became the precedent that state PUCs follow in assessing adequate revenue requirements for utilities in their jurisdictions. But it established no precise formula for doing so. It did not matter to the court whether a utility earned a low return on a high capital base, or a high return on a small base, as long as these principles were upheld. As a result, PUCs now have considerable discretion with regard to the actual procedures used to determine rates.

## Determination of Revenue Requirements

The determination of adequate utility revenues occurs within the context of a quasijudicial rate case hearing at which the utility's prices, or rates, are set. Following the precedent of the Hope decision, utility revenues would be considered adequate when the prices utilities charge for their electricity sales are equal to the costs of providing electricity ("cost of service"), plus some subjective "fair" rate of return on the value of the utility's assets (the rate base). Thus, there are three major judgments a PUC must make in a rate case: the cost of service, the value and content of the rate base, and the rate of return on this rate base.

There is little theoretical disagreement as to what the cost of service should comprise. Allowable expenses include fuel costs, operation and maintenance costs, depreciation of the capital stock, administrative expenses, and taxes. An estimate of total expenses for the coming year is typically derived by utilizing an historical "test year." A test year is usually

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1. Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1944).

the most recent 12-month period for which complete financial data are available. Yet "test year" expenses often may not be representative and will require adjustments, as when there is a sudden increase in the price of fuel. During inflationary times, of course, an historical test year will underestimate revenue requirements.

Beyond the choice of a test year, the controversial issues in a rate hearing generally concern the rate base and the allowed rate of return. The rate base is the electric utility's gross capital investment less accumulated depreciation--in essence, the value of that property which is "used and useful" in producing and delivering electricity. As such it includes the values of all physical assets of the electric utility--land, buildings, generation stations, and transmission facilities. These can be valued using one of three methods: original cost, replacement cost, or "fair value," which constitutes a compromise between the first two. All but five state PUCs utilize the original-cost method of rate base valuation calculated at the year's end or as an average over the year. The others use a "fair value" method.

An electric utility's allowed rate of return is usually related to the cost of capital: the weighted average of the return to be paid on long-term debt (bonds) and preferred and common stock (equity). For debt and preferred stock, the annual interest or dividend requirement is fixed, and its determination is straightforward. The rate of return on common equity is not fixed and hence is more difficult to determine. Historically, determination of the rate of return on common equity and the rate base have occupied the largest part of rate cases, since the rate allowed on common equity will affect the utility's ability to raise capital competitively.

## Issues in Rate Base Regulation

The principal issues that PUCs face in determining utility revenue requirements include:

- Whether or not to allow construction work in progress to be included in the rate base;
- How to derive a "fair" rate of return on the rate base;
- Which of various accounting practices to use; and
- The use of fuel adjustment clauses.

Construction Work in Progress (CWIP). Traditionally, utilities have not been allowed to earn a return on CWIP. This means that capital expenditures on plant and equipment and on transmission and distribution facilities that are still under construction, but not yet "used and useful," are not included in the rate base. Instead, these funds are segregated in a special account--the Allowance for Funds Used During Construction account (AFUDC). The AFUDC return is calculated by multiplying the value of the utility's construction work in progress by the allowed rate of return on capital. This amount appears on the books as income for accounting purposes, but will not be realized as income by the utility until the facility is placed in service. At that time the (capitalized) AFUDC income, along with total construction costs, will be placed in the rate base and earn the rate of return applied to the rest of the utility's capital. This amount will be depreciated over the life of the new facility, and an annual return will be allowed on the undepreciated portion. Until then, the utility must maintain its cash flow in other ways.

The most common argument against the inclusion of CWIP in the rate base is that it would require current ratepayers to subsidize future ratepayers. Yet, there is emerging evidence that the opposite may occur. Since AFUDC is only accounting income and not cash, its use reduces short-run cash flow. Therefore, as AFUDC increases as a percent of a utility's total revenues, the "quality" of utility earnings is diminished, and the likelihood that the utility will be unable to meet its bills increases. The investment community then perceives lending to the utility as riskier, and interest costs rise. Thus, it is not always in the best interest of current ratepayers to favor the use of AFUDC rather than CWIP, if higher interest costs are reflected in current rates. Perhaps more important, incentives to make economic capital expenditures may be reduced if AFUDC is employed.

"Fair" Rates of Return. The "fair" rate of return is derived from a utility's cost of capital. The cost of capital is weighted in proportion to the amount of debt, preferred stock, and common stock comprising the utility's capital structure. Interest payments on long-term debt are fixed, as are the dividends on preferred stock. Thus, the most controversial part of the rate case is the determination of a fair return on common stock.

The cost of common equity is higher than either bonds or preferred stock. This is because bondholders and preferred stockholders have rights to payment prior to those for common shareholders, so that common stock is riskier than bonds or preferred stock. In determining a rate of return on common equity, this risk must be assessed by examining the capital structure of the utility. The larger the percentage of preferred stock and debt, the more risky is the common stock, justifying a higher rate of return.

Another type of risk to be considered in rate-of-return determination derives from one of the principles of the Hope decision: that a utility should earn a return comparable to other companies facing circumstances of similar risk. Determination of "similar risk" may not be practical in rate case hearings, since there will be disagreement as to the appropriate set of firms with similar risks. In addition, mathematical methods are sometimes used to help regulators determine a "fair" rate of return on common equity. Chief among these are the discounted cash flow technique--the most frequently used--and the capital asset pricing model, which is new but growing in popularity. But inevitably a large subjective element will remain.

Regulatory Accounting Techniques. Accounting practices pose two important regulatory choices affecting the electric utility sector: the choice between "flow-through" and normalized treatment of federal tax subsidies, and the choice of test period for cost estimation. The first choice concerns the regulatory treatment of federal tax benefits. Flow-through treatment passes the utility's tax benefits from accelerated depreciation and the investment tax credit through to ratepayers in the year that these benefits occur. Under flow-through accounting, tax benefits directly subsidize electricity use rather than the cash-flow position of the utility. By contrast, normalized treatment passes these benefits on more slowly than they are received, by amortizing the tax subsidy over the life of the capital asset that produced it. This increases the utility's effective cash flow and provides a smaller immediate benefit to ratepayers. Most states now use the normalized method for investment tax credits and accelerated depreciation. Under the Economic Recovery Tax Act of 1981, normalization of the investment tax credit and accelerated depreciation is mandatory for public utility property placed in service after 1980.

The choice of an accounting test period for estimating costs is very important during inflationary times because of the inherent regulatory lag encountered in the processing of rate cases. The average decision time for rate cases over the past five years has been eight and one-half months, and many cost estimates are outdated by the time rates go into effect. To the extent that this occurs, the utility finds it difficult to realize the revenue requirements settled in the rate case. This is especially true for cost estimates based on historical data, usually some past 12-month period. Currently, no PUCs use strictly historical test periods. Rather, most utilize an adjusted historical test period in which cost data are adjusted for known inflation. A number of PUCs utilize a partially projected test period, typically a combination of six months of adjusted historical data and six months of projected data. A few PUCs use a test period totally comprised of projected data.

Fuel Adjustment Clauses. Because of the time lag that characterizes ratemaking proceedings, PUCs have had to find a way to deal with the



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unanticipated increases in fuel prices of recent years. Fuel adjustment clauses (FACs) have been the regulatory response to this problem. All but seven PUCs use some sort of fuel adjustment clause. These clauses allow the recoupment of increases in fuel costs between rate hearings by increasing rates outside the context of a full rate case. There are a variety of such clauses, allowing all or part of the fuel cost increase to be recouped immediately or with a specific time lag. Again, each PUC uses its own discretion in designing a fuel adjustment clause it feels is appropriate for its jurisdiction.

While the use of FACs may be justifiable as a short-term measure to protect utility earnings in times of rapid and unpredictable escalation in fuel prices (such as the oil price shocks of 1973 and 1979), it can create a number of perverse incentives. Most importantly, it may deter a utility from undertaking investments to change its fuel mix. Given the long lead times required for new capacity additions, this can entail significant long-term inefficiencies.

FACs can also create short-term inefficiencies. A utility with such a clause may not bargain effectively for the lowest-priced fuel available. Similarly, operation and maintenance expenditures may not be kept at appropriate levels, increasing downtime for repairs. This diminution in reliability may force the utility to use less efficient units of its own, or to purchase replacement power from another utility (often oil- or gas-fired). A number of studies have attempted to quantify the inefficiencies such perverse incentives produce. One recent endeavor estimated the combined losses from fuel-switching and ineffective bargaining in the two years 1977 and 1978 at $4.9 billion.[2] This may be an understatement since the sample consisted of only 121 private utilities; there are over 120 other private utilities, many of which use FACs.

A more limited study of operation and maintenance expenditures was recently conducted by the Pennsylvania PUC.[3] It concluded that Pennsylvania members of the Pennsylvania-New Jersey-Maryland Power Pool could reduce cumulative production costs by $428 to $703 million over the period 1982 to 1987. It estimated that additional maintenance expenditures of $13

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2. David L. Kaserman and Richard C. Tepel, "The Impact of the Automatic Adjustment Clause on Fuel Purchase and Utilization Practices in the U.S. Electric Utility Industry," The Southern Economic Journal, vol. 48, no. 3 (January 1982), pp. 687-700.

3. Pennsylvania Public Utility Commission, Electric Power Plant Productivity Related to Plant Availability (December 1980).

million in 1982 could lead to production cost savings of $81 million to $128 million, or $6.30 to $9.80 in production costs per maintenance dollar.

## THE FINANCIAL CONDITION OF ELECTRIC UTILITIES

The financial performance of electric utilities in the United States is one measure of how well the PUCs have succeeded in setting rates consistent with the principles of the Hope decision. Of course, the quality of management and the state of the economy are also important factors in financial performance. Indeed, the purpose of regulation is to make an adequate rate of return possible, but not to compel such a return under all circumstances.

Many electric utilities face financial problems today, not only because of dramatic changes in the economic environment of the industry during the 1970s, but also because of specific aspects of the regulatory environment. This section discusses the current financial condition of electric utilities, traces their progressive financial decline through the 1970s, and reviews the performance of the rate base method of regulation.

### Recent History

During the 1960s, electric utilities successfully lowered their costs through scale economies (decreases in unit costs associated with larger operations) and technological advances. The average size of a new electric steam unit increased from 102 megawatts during the decade ending in 1960 to 203 megawatts during the decade ending in 1970. Currently, new units are from three to five times this size. Similar scale economies occurred in transmission networks. Technological advances during the 1960s included improved design of boilers, turbines, transformers, and transmission lines that permitted a decrease in per unit capital costs. There were no environmental controls in the 1960s on either sulfur dioxide emissions or solid waste disposal, and only minimal controls on particulate emissions. In that decade, electricity demand increased at a constant rate of about 7 percent annually, and construction time for new plants averaged two years. This environment made it easy to plan for capital expansion. As a result, the price of electricity for consumers dropped significantly during 1961-1966, and continued to drop during the 1967-1970 period of constant average costs. Table 1 shows the steady decline in average revenue per kilowatt hour sold from 1960 through 1970, adjusted for inflation.

It was in the interest of electric utilities to lower prices to consumers, since expanding sales meant increased profits. Table 1 shows the steady

TABLE 1. FINANCIAL STATISTICS OF ELECTRIC UTILITIES, 1960-1980

| Year | Utility Earned Rate of Return on Equity (percent) | Allowed Return on Equity (percent) a | Earned Rate of Return Excluding AFUDC (percent) | Earned Rate of Return Total Manufacturing (percent) |
|---|---|---|---|---|
| 1960 | 11.5 | -- | 10.8 | 10.6 |
| 1961 | 11.6 | -- | 11.1 | 9.9 |
| 1962 | 12.0 | -- | 11.5 | 10.9 |
| 1963 | 12.2 | -- | 11.8 | 11.6 |
| 1964 | 12.6 | -- | 12.2 | 12.6 |
| 1965 | 12.9 | -- | 12.4 | 13.9 |
| 1966 | 13.2 | -- | 12.6 | 14.2 |
| 1967 | 13.1 | -- | 12.2 | 12.6 |
| 1968 | 12.5 | -- | 11.3 | 13.3 |
| 1969 | 12.5 | -- | 10.9 | 12.4 |
| 1970 | 12.2 | -- | 10.0 | 10.1 |
| 1971 | 12.0 | -- | 9.4 | 10.8 |
| 1972 | 12.2 | -- | 9.1 | 12.1 |
| 1973 | 11.8 | -- | 8.6 | 14.9 |
| 1974 | 10.4 | 12.5 | 7.2 | 15.2 |
| 1975 | 11.5 | 12.9 | 8.3 | 12.6 |
| 1976 | 11.6 | 12.8 | 8.5 | 15.0 |
| 1977 | 11.5 | 13.1 | 8.0 | 14.8 |
| 1978 | 11.8 | 13.2 | 7.8 | 16.0 |
| 1979 | 11.4 | 13.4 | 6.8 | 18.3 |
| 1980 | 12.0 | 14.1 | 6.4 | 16.4 |

SOURCES: Duff and Phelps, Inc. (earned return on equity); Edison Electric Institute (allowed return on equity, AFUDC as a percent of net income, and average revenue per kilowatt hour); CBO (earned return excluding AFUDC); Citibank, Economics Department (earned rate of return manufacturing); Moody's Public Utility

increase in the rate of return that occurred from 1960 through 1966, due in part to the fact that during the period costs continually declined after rates were set. Since lowering the earned rate of return required initiation of a full rate case hearing, a natural inertia on the part of state PUCs allowed electric utilities to retain excess profits as capacity expanded and electricity costs fell. Rate-of-return reviews by state PUCs during the 1961-1968 period averaged only five per year. In contrast, 52 reviews were conducted

TABLE 1. (Continued)

| Bond Yields (percent) | AFUDC as a Percent of Net Income | Real Average Revenue per Kilowatt Hour Sold (1980 dollars)[b] | Cost (1980 dollars)[b] | Year |
|---|---|---|---|---|
| 4.84 | 5.7 | 4.70 | 3.95 | 1960 |
| 4.70 | 4.6 | 4.66 | 3.91 | 1961 |
| 4.44 | 4.3 | 4.52 | 3.77 | 1962 |
| 4.39 | 3.6 | 4.38 | 3.64 | 1963 |
| 4.56 | 3.6 | 4.22 | 3.51 | 1964 |
| 4.68 | 3.7 | 4.05 | 3.36 | 1965 |
| 5.61 | 4.8 | 3.86 | 3.21 | 1966 |
| 6.01 | 6.6 | 3.72 | 3.10 | 1967 |
| 6.72 | 9.3 | 3.52 | 2.95 | 1968 |
| 7.99 | 12.9 | 3.33 | 2.80 | 1969 |
| 8.85 | 17.8 | 3.26 | 2.74 | 1970 |
| 7.71 | 21.8 | 3.29 | 2.79 | 1971 |
| 7.46 | 25.1 | 3.30 | 2.80 | 1972 |
| 7.88 | 26.7 | 3.31 | 2.84 | 1973 |
| 9.21 | 31.0 | 3.86 | 3.49 | 1974 |
| 9.76 | 28.2 | 4.15 | 3.77 | 1975 |
| 8.80 | 27.1 | 4.18 | 3.90 | 1976 |
| 8.38 | 30.3 | 4.36 | 4.08 | 1977 |
| 9.22 | 33.9 | 4.37 | 4.11 | 1978 |
| 10.64 | 40.1 | 4.35 | 4.14 | 1979 |
| 13.09 | 46.3 | -- | 4.53 | 1980 |

Manual, 1981, vol. 1 (bond yields); U.S. Department of Energy, Energy Information Administration, Statistics of Privately Owned Electric Utilities (costs).

a. Data not available before 1974. b. Cents per kilowatt hour.

in 1972 alone. Ninety percent of all electric utilities had only two or fewer formal rate hearings in the period 1958-1972. Many utilities now have such a hearing annually.

The rate of return earned by utilities began to decline after the late 1960s as the cost reductions associated with increased scale were exhausted. Since profits were high, many utilities were able to tolerate this. But when cost of service began its long-term upward trend, many companies were not able to earn their allowed rates of return. Consequently, the number of rate cases increased dramatically, beginning in 1968 and 1969.

The number of formal rate-of-return hearings continued to increase in the 1970s, and their processing time (or regulatory lag) also increased. General inflation, which took hold in the late 1960s, persisted throughout the entire decade of the 1970s. This, combined with regulatory lag, continually squeezed electric utility profits until a substantial and increasing number were unable to earn their allowed rates of return. In addition, the cost of financing began to rise sharply. The average cost of common equity rose from 6 percent during the 1960-1970 decade to 11 percent in the 1970-1975 period. Table 1 shows that bond yields--the cost of debt financing--rose from 4 or 5 percent in the early and middle 1960s to 9 or 10 percent in the late 1970s and 13 percent in 1980.

A variety of factors combined during this period to increase utility capital costs. The most important of these was the exhaustion of scale economies. Contrary to the experience of the early 1960s, generating costs no longer declined as the size of utility operations expanded. Further cost increases arose from chronic delays in capacity additions. Frequently these were nuclear. A delay in the licensing of a nuclear power plant, for example, could increase the capital costs of that plant by $6 million per month.[4] For coal plants, the passage of the Clean Air Act Amendments of 1977, and subsequent regulations, required strict sulfur dioxide, particulate, and solid waste controls. It added approximately 20 to 30 percent to the capital costs of a new coal plant with its requirement of flue gas desulfurization (scrubbing) and particulate control equipment. These environmental costs had not previously been confronted. Finally, inflation in the construction industry was generally more rapid than in the economy as a whole, further adding to the capital costs of power plants.

## The Response of the Regulatory Process

State PUCs were able to satisfy both consumer and producer interests during the 1960s. Consumers were content with declining electricity prices, while producers gained from increasing returns to scale. When these circumstances changed during the 1970s, both groups became increasingly discontent.

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4. Congressional Budget Office, Delays in Nuclear Reactor Licensing and Construction: The Possibilities for Reform, Background Paper (March 1979).

Electric utilities, unable to earn their authorized rate of return, initiated many rate cases. In addition, with the advent of the 1970 Clean Air Act, environmental concerns were incorporated into the regulatory process. The constant interaction of these three groups--utilities, consumers, and environmentalists--in an ongoing inflationary environment confronted state PUCs with the need for new decisions. To deal with the unprecedented inflation rate, the PUCs now had to consider each element of the revenue requirement formula discussed at the outset of this chapter. Questions of whether to calculate the cost of capital equipment at its historical rate or at its substantially higher replacement cost, whether or not to use projected test periods, what accounting technique to utilize, and how to design fuel adjustment clauses, all became contentious issues.

In general, the state PUCs were slow to adapt their regulatory practices to these unprecedented circumstances. Projected test periods were not widely adopted, nor was the replacement or reproduction cost method of rate base valuation. Regulatory lag, the time associated with the processing of a formal rate case, increased with the dramatic growth in rate cases. In the inflationary environment of the 1970s, electric utilities typically experienced a significant difference between their anticipated revenue requirements and the larger amounts later found necessary. While this was partly attributable to less-than-anticipated demand, much of it resulted from regulatory lag that prevented utilities from fully recouping required revenues. The result was that many encountered increasing difficulty in earning their allowed rate of return, and their cash flow was impeded. Table 1 shows the increasing discrepancy between earned and allowed rates of return on common equity after 1975. By 1980, the differential was two percentage points.

The earnings of utilities were also affected by growing use of the AFUDC account. Rather than allowing new and unfinished investment (construction work in progress) to enter the rate base, many regulatory commissions sequestered it in AFUDC "promissory notes" instead. AFUDC income has increased dramatically as a percent of net income, from 17.8 percent in 1970 to an estimated 46.3 percent in 1980. Since AFUDC income is only accounting money, it reduces the cash available for interest payment and stock dividends and thus diminishes the quality of utility earnings. As can be seen in Table 1, when AFUDC accounts are excluded from the calculation of earnings, utilities earn a much lower rate of return. In 1972, for example, utilities earned a 12 percent rate of return, approximately equal to the rate earned by all manufacturing. Yet, when corrected for AFUDC, utilities' earnings dropped to slightly over 9 percent. By 1980, utilities earned a 12 percent rate of return, but only 6.4 percent if AFUDC is excluded. In contrast, the rate of return for all manufacturing in 1980 was over 16 percent.

The willingness or unwillingness of PUCs to grant rate relief are only one aspect of the regulatory problem in financing utility investment. Another is the increased sensitivity to the environmental costs and risks associated with coal-fired and nuclear plants, which has contributed to the increased time required to plan, site, and construct a generating facility (from an average of four or five years in the 1960s to about twelve years today). Longer construction periods, and the general unwillingness of PUCs to include CWIP in the rate base, require the utilities to borrow more per dollar of construction, raising the financing costs for every investment project.

# CHAPTER III. INEFFICIENCY IN THE ELECTRIC UTILITY SECTOR

A rapidly changing business environment and the slow adaptation of many regulatory practices have contributed to the general financial decline of electric utilities and their diminished ability to make economic capital expenditures. This inability may affect the efficiency with which electricity is produced and, in turn, the composition of fuels used in the economy. The potential inefficiency may reveal itself through one of two effects: an incorrect use of fuels in generating, and a failure to construct enough new capacity.

With regard to fuel choice, electric utilities may continue to carry a considerable amount of oil- and gas-fired capacity that is uneconomic under a reasonable range of assumptions regarding future fuel prices and interest rates. This suggests that installations may not be configured to produce electricity in the least-cost fashion. With regard to the construction of new capacity, regulators have often held the rate of return allowed utilities to a level below the cost of new capital. If electricity demand grows substantially in the 1980s and capacity additions are slow to occur, generating capacity reserve margins could drop precipitously in many regions of the country.

These two problems--the problem of incorrect fuel choice dictated by existing plant, and the problem of inadequate generating capacity--are essentially a single problem. In order to avoid serious power shortages, utilities and their corresponding public utility commissions (PUCs) have the option of calling up generating units that would otherwise be inappropriate for baseload generation: peaking units, units slated for retirement, or reserve capacity in other regions (whose power would be transferred, or wheeled, into the relevant region). But most of these backup sources of generating capacity rely on oil or gas. Thus the result of inadequate generating capacity would not be blackouts, but increased use of otherwise uneconomic fuels.

This chapter examines the costs imposed on the economy by an incorrect utility fuel mix. It first presents data on the fuel composition of the utility generating stock and its regional breakdown. It then discusses the comparative costs of oil- and gas-fired generation and its major alternative, the use of coal. Finally, it provides projections of the utility fuel mix under alternate scenarios of electricity supply and demand, and estimates the extra cost burden imposed on the economy by inappropriate baseload generating capacity.

## PATTERNS OF UTILITY FUEL USE

Electric utilities consumed the equivalent of 2.8 million barrels per day of oil and natural gas in 1981. By 1990, the use of these fuels is projected to decline to 1.9 million barrels per day. Nevertheless, over half of that use may still be uneconomic.

The expansion of electric power output in the past three decades has drawn heavily on primary energy sources. In 1949-1980, energy used in electricity production more than doubled as a percent of total U.S. energy consumption. As Table 2 shows, electric utilities accounted for 33.3 percent of total domestic energy consumption in 1981. Table 3 shows the percentage of total generation accounted for by each fuel type in 1981. Coal was by far the most important fuel, producing 52.4 percent of total electricity generated. Natural gas and oil produced 15.1 percent and 9.0 percent, respectively, and hydroelectric units 11.4 percent, of total electricity generated in that year. Nuclear energy provided 11.9 percent. Table 3 also translates these figures into oil equivalents. Utilities used about 1.0 million barrels a day in residual fuel oil to produce electricity in 1981. Utility natural gas use was equal to 1.6 million barrels of residual fuel oil per day. Together oil and gas produced nearly 24 percent of total electricity generated in 1981, or the equivalent of 2.6 million barrels per day of oil. This figure represents approximately one-half of net oil imports, and 18 percent of total petroleum products supplied in that year. Thus, as compared to other alternatives for reducing oil imports, displacing oil and natural gas in the utility sector may be an attractive option.

Utility fuel use varies among the nine regions defined by the National Electricity Reliability Council (Figure 1). As may be seen in Table 4, the Northeast is by far the most oil-reliant of all regions, depending on that fuel for 44 percent of its electricity. The Mid-Atlantic region uses oil to produce 23 percent of its electricity. Oil use is substantial in the Southeast (14 percent), and particularly in Florida (49 percent). The West is reliant on both oil (16 percent) and natural gas (14 percent). Texas relies on natural gas for 72 percent of its primary fuel input and the Southwest region relies upon natural gas for 61 percent of its primary fuel input. Other regions depend predominantly on coal.

## THE ECONOMICS OF OIL AND GAS REPLACEMENT

Generating capacity is of three distinct kinds. The first is baseload capacity. Because baseload units produce the least costly electricity when run at high capacity factor, they are relied upon most heavily to meet demand. Those that are fueled with coal or uranium have high capital

TABLE 2. INSTALLED GENERATING CAPACITY AND ENERGY CONSUMPTION OF THE ELECTRIC UTILITY INDUSTRY, SELECTED YEARS (1949-1980)

| | Capacity (millions of kilowatts) | | | | | | | Energy Consumption (quadrillions of Btus) | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | Electric Utilities | |
| Year | Conventional Steam[a] | Hydropower | Internal Combustion | Gas Turbine | Nuclear Power | Geothermal | U.S. Total | U.S. Total | Total | As Percent of U.S. |
| 1949 | 44.6 | 16.7 | 1.8 | -- | -- | -- | 63.1 | 31.08 | 4.66 | 15.0 |
| 1950 | 49.3 | 17.7 | 1.9 | -- | -- | -- | 68.9 | 33.62 | 5.02 | 14.9 |
| 1955 | 87.1 | 25.0 | 2.4 | -- | -- | -- | 114.5 | 39.17 | 6.79 | 17.3 |
| 1960 | 132.1 | 32.4 | 2.8 | -- | 0.3 | --[b] | 168.0 | 44.08 | 8.23 | 18.7 |
| 1965 | 186.6 | 43.8 | 3.4 | 1.4 | 0.9 | --[b] | 236.1 | 52.99 | 11.07 | 20.9 |
| 1970 | 260.0 | 55.1 | 4.4 | 15.5 | 6.5 | 0.1 | 341.6 | 66.83 | 16.29 | 24.4 |
| 1971 | 277.8 | 55.9 | 4.5 | 21.9 | 8.7 | 0.2 | 368.9 | 68.30 | 17.22 | 25.2 |
| 1972 | 294.1 | 56.4 | 4.8 | 27.7 | 15.3 | 0.3 | 398.6 | 71.63 | 18.58 | 25.9 |
| 1973 | 320.6 | 62.0 | 5.0 | 33.4 | 21.0 | 0.4 | 442.4 | 74.61 | 20.01 | 26.8 |
| 1974 | 337.3 | 63.6 | 5.0 | 39.6 | 31.6 | 0.4 | 477.6 | 72.76 | 20.16 | 27.7 |
| 1975 | 352.9 | 65.9 | 5.1 | 44.1 | 39.8 | 0.6 | 508.3 | 70.71 | 20.42 | 28.9 |
| 1976 | 367.9 | 67.7 | 5.3 | 46.6 | 42.9 | 0.6 | 531.0 | 74.51 | 21.55 | 28.9 |
| 1977 | 387.8 | 68.7 | 5.3 | 47.9 | 49.9 | 0.6 | 560.2 | 76.33 | 22.82 | 29.9 |
| 1978 | 399.5 | 71.0 | 5.5 | 49.0 | 53.5 | 0.6 | 579.2 | 78.18 | 23.55 | 30.1 |
| 1979 | 411.6 | 75.3 | 5.5 | 50.6 | 54.6 | 0.7 | 598.3 | 78.91 | 24.14 | 30.9 |
| 1980 | 423.5 | 76.4 | 5.5 | 50.6 | 56.5 | 1.0 | 613.5 | 75.91 | 24.44 | 32.2 |
| 1981[c] | 438.6 | 77.1 | 5.6 | 51.4 | 60.7 | 1.0 | 634.5 | 73.91 | 24.63 | 33.3 |

SOURCE: Energy Information Administration, Annual Report to Congress (1981), vol. 2.
NOTE: Sum of components may not equal total due to independent rounding.

a. Excludes geothermal. b. Less than 0.05 million kilowatts. c. preliminary.

TABLE 3. ENERGY CONSUMED AND PRODUCED BY ELECTRIC UTILITIES, 1981

| Unit of Measurement | Coal | Natural Gas | Oil | Hydro-electric Power | Nuclear Electric Power | Other | Total |
|---|---|---|---|---|---|---|---|
| Millions of Kilowatt Hours Produced | 1,203,203 | 345,777 | 206,421 | 260,684 | 272,674 | 6,054 | 2,294,812 |
| Primary Energy Consumed | 596,797 (thousands of tons) | 3,640,154 (millions of cubic feet) | 351,111 (thousands of barrels) | | | | |
| Percent of Generation | 52.4 | 15.1 | 9.0 | 11.4 | 11.9 | 0.3 | — |
| Residual Oil Equivalent Consumed (thousands of barrels per day)[a] | 5,675 | 1,631 | 962.0 | 1,230 | 1,286 | 29 | 10,813 |

SOURCE: Monthly Energy Review (April 1982).

a. Calculated at 6.2 million Btus per barrel.